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Transitioning to zero freshwater withdrawal in the U.S. for thermoelectric generation

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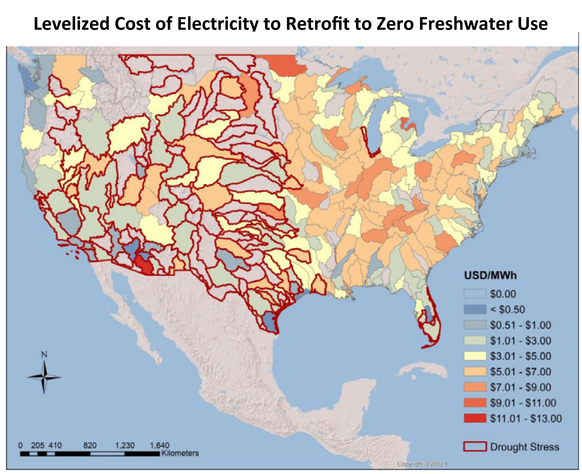
HIGHLIGHTS

- Scoping level cost analysis to retrofit thermoelectric generation to achieve zero freshwater use.
- Least cost alternative is determined for 1178 freshwater using power plants in the U.S.
- Projected increase in levelized cost of electricity has a median value of \$3.53/MW h.
- Retrofits would alleviate system vulnerabilities and save 3.2 Mm^3/d of water in stressed basins.
- Impact on wastewater and brackish water supply is minimal as are parasitic energy requirements.

GRAPHICAL ABSTRACT



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ABSTRACT

Drought poses important risks to thermoelectric power production in the United States because of the significant water use in this sector. Here a scoping level analysis is performed to identify the technical tradeoffs and initial cost estimates for retrofitting existing thermoelectric generation to achieve zero freshwater withdrawal and thus reduce drought related vulnerabilities. Specifically, conversion of existing plants to dry cooling or a wet cooling system utilizing non-potable water is considered. The least cost alternative is determined for each of the 1178 freshwater using power plants in the United States. The projected increase in levelized cost of electricity ranges roughly from \$0.20 to \$20/MW h with a median value of \$3.53/MW h. With a wholesale price of electricity running about \$35/MW h, many retrofits could be accomplished at levels that would add less than 10% to current power plant generation expenses. Such retrofits would alleviate power plant vulnerabilities to thermal discharge limits in times of drought (particularly in the East) and would save 3.2 Mm^3/d of freshwater consumption in watersheds with limited water availability (principally in the West). The estimated impact of retrofits on wastewater

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and brackish water supply is minimal requiring only a fraction of the available resource. Total parasitic energy requirements to achieve zero freshwater withdrawal are estimated at 140 million MW h or roughly 4.5% of the total production from the retrofitted plants.

1. Introduction

In 2005 thermoelectric power generation was the largest user of freshwater in the United States, withdrawing over 530 million cubic meters per day (Mm^3/d) [1]. The high dependence on freshwater puts power production at risk in times of drought or heat waves as evidenced by past climate impacts on power production [2–5]. Vulnerabilities arise both from reduced water availability as well as thermal intake/discharge limits (i.e., intake water is too hot to efficiently operate the power plant or the power plant discharge poses a threat to the environment due to its elevated temperature). Drought is likely to intensify in many areas of the United States [6–8], given projected effects of climate change combined with growing demands on freshwater supplies by the energy sector [9] and other sectors (e.g., agriculture, industry, public) [10].

There are a variety of ways to reduce the dependency of the electricity sector on freshwater. Others have assessed the water and financial impacts of fuel switching from coal to natural gas technologies [11], shifting to higher renewable energy scenarios [12,13], or retrofitting existing once-through cooled facilities to recirculating cooling systems [14]. One additional way of reducing the electricity sector's vulnerability to drought would be to lessen the dependence of thermoelectric generation on freshwater. This could be achieved by retrofitting current power plants to use non-potable water (e.g., brackish groundwater or municipal wastewater) or converting to a dry cooling system [15]. Such measures would help to avoid competition over limited freshwater supplies and reduce effluent discharge to aquatic systems (e.g., streams, rivers, and reservoirs). However, such efforts would not necessarily alleviate all water vulnerability concerns for the power sector as the availability of municipal wastewater and brackish groundwater resources are subject to competition among different sectors.

Several research efforts have focused on the current and possible future application of municipal wastewater in thermoelectric cooling [16–20]. One assessment of wastewater effluent as a cooling water supply for existing coal-fired power plants determined that 81% of existing plants' demand could be met with wastewater within a 10 mile radius of the power plant and 97% could be met by wastewater sources within a 25 mile radius [18]. Li et al. [20] briefly assessed the technical challenges and regulations associated with using wastewater in energy production. In addition, ALLConsulting developed the Alternative Water Source Information System (http://www.all-llc.com/projects/coal_water_alternatives/page.php?13) which identifies alternative water sources within a 15 mile radius of coal-fired power plants and displays the results in Google Earth.

The intent of this effort is to provide a "coarse," scoping level analysis of the feasibility, technical tradeoffs and initial cost estimates for retrofitting existing thermal generation to achieve zero freshwater withdrawal. The analysis also explores how such adaptive measures impact water resources; particularly in relation to the potential for reducing the vulnerability to drought. Assumptions on anticipated water and temperature constraints and unit level operational water requirements draw upon existing references. These data are used to determine the least cost alternative for existing power plant retrofits of either dry cooling or a wet cooling system that utilizes municipal wastewater or brackish groundwater. Where needed, conversion from open-loop to recirculating cooling is also considered. This analysis does not consider the cost tradeoffs of retrofitting a facility compared with the plant and societal-level costs associated with power plant shut downs and curtailments, nor does it evaluate the physical and legal feasibility of retrofits at individual power plants; these remain areas of future research.

2. Methods

To assess the potential of retrofitting power plants in the United States to achieve zero freshwater use, the following steps were taken:

- The existing fleet of 1178 freshwater using power plants was characterized, including their water use requirements and cooling system technology.
- Available non-potable water sources were identified based on type, size, availability, and location.
- Cost models were developed for retrofitting a particular power plant from once-through cooling to recirculating cooling and dry cooling, as well as for converting a recirculating cooling system to use brackish groundwater or municipal wastewater instead of freshwater.
- Drought vulnerable regions were identified based on a metric constructed from the ratio of consumptive water use to gauged streamflow.

This data was then incorporated into a custom algorithm that identified the least cost alternative among the three cooling technologies for each of the 1178 power plants based on nearby non-potable water resource availability and the cost of the cooling retrofit. The three technologies include: dry cooling, recirculating cooling using brackish water, and recirculating cooling using municipal wastewater. The results for each individual power plant were then aggregated at the 6-digit Hydrologic Unit Code (HUC) [21] watershed level (total of 377 watersheds) to determine the cost and potential to retrofit the fleet across the United States with particular focus on drought vulnerable regions. Plant level results are aggregated by 6-digit HUC to provide a convenient basis for evaluating water resource implications of retrofitting the thermoelectric power plant fleet, and to avoid singling out potentially sensitive results for individual power plants.

2.1. Resource evaluation

2.1.1. Power plant characteristics

The impacts of alternative cooling systems on water usage and system efficiency were projected for each freshwater-using power plant in the U.S. For the purposes of this analysis, power plants recorded in the Energy Information Agency [EIA] forms 860 [22] and 923 [23] were distinguished according to fuel type (coal, nuclear, oil, natural gas, biopower/biogas, concentrating solar power, and geothermal), prime mover technology (steam plant and combined cycle), and cooling system type (once-through, recirculating, and pond which is treated the same as once-through). This plant classification scheme, which is driven by the availability of data, lacks some of the resolution available in the EIA databases. For example, subcritical and supercritical coal steam

plants utilizing natural draft and mechanical draft recirculating cooling systems are aggregated into one category with identical cost (dollars/kW) and performance (percentage of generation) penalties applied for retrofits. A detailed accounting of each power plant can be accessed through the Union of Concern Scientists [24].

Retrofit impacts on power plant efficiency were determined on a fuel-specific basis as a percentage reduction of generation (relative to 2008 generation and existing cooling system data, as reported in Averyt et al. [25] from the EIA databases). Projected freshwater withdrawal and consumption values from the National Renewable Energy Laboratory (NREL) [26] are applied to EIA reported and modified generation. Based on this analysis total national water consumption of freshwater by thermoelectric power generation is estimated at 18.4 Mm^3/d while withdrawals require 540 Mm^3/d. Thermoelectric freshwater consumption and withdrawal are mapped at the 6-digit HUC level in Fig. 1. Note that consumption is noticeably higher in the Midwest and Mountain West owing to the extensive generation by coal and nuclear fuels, while basins with high withdrawals are associated with thermoelectric generation utilizing open-loop cooling systems.

2.1.2. Municipal wastewater availability

Municipal wastewater discharge data is available through the EPA's Permit Compliance System [27], and Clean Watershed Needs Survey [28], which provide information on the location, discharge, and level of treatment for most wastewater treatment plants in the United States. Additionally, the United States Geological Survey publishes municipal wastewater discharge values aggregated at the county level [1]. These three sources of information were combined to provide a comprehensive view of wastewater discharge across the United States.

However, not all wastewater is available for future use. A considerable fraction of the water is currently re-used by industry, agriculture, and thermoelectric generation. Re-use estimates were determined both from the USGS [1] data as well as the EPA databases as they record the point of discharge (e.g., stream, agriculture, power plant). These re-use estimates were subtracted from the projected discharge values.

For the states west of the 100th meridian, consideration of water rights must be made. Those municipalities that discharge to perennial streams receive return flow credits for treated wastewater. This water is not available for new development as it is already being put to beneficial use downstream by others. Unfortunately, there are no comprehensive data on wastewater return flow credits. In efforts to identify plants that are likely credited for their return flows, those plants that directly discharge to a perennial stream are identified (point of discharge is listed in the databases noted above). These plants are excluded as a source of available municipal wastewater.

2.1.3. Brackish water availability

For this analysis brackish water availability is defined as a resource at a depth less than 760 m and salinity between 1000 and 10,0000 TDS [29]. Deeper, more concentrated resources would generally be very expensive to exploit. Additionally, resources with both a depth and salinity less than 15 m and 3000 TDS, respectively are excluded as an available brackish resource. This prohibition is necessitated as such sources are likely in communication with local surface water and thus are permitted as a potable water source in many states.

Estimates of brackish water resources across the U.S. are limited, so multiple sources of information were utilized. These data were used to map availability at the 6-digit HUC level. The best quality data were state estimated volumes of brackish groundwater that are potentially developable; however, data were only available for Texas [30], New Mexico [31], and Arizona [32]. Most states apply some type of allowable depletion rule to water sources. In this case, it is assumed that only 25% of the resource can be depleted over a 100 year period of time.

The next best source was reported use of brackish groundwater as published by the USGS [1]. This does not provide a direct measure of available water, simply an indication that brackish water of developable quality was present. Conservatively, we assumed that double the existing use could be developed up to a maximum limit of 0.04 Mm^3/d. Also assumed was that the minimum quantity available was 0.004 Mm^3/d.

Finally, if a watershed has no brackish water volume estimate, or brackish water use, then the presence of brackish groundwater wells was used. The USGS maintains the National Water Information System (NWIS) database that contains both historical and real-time data of groundwater well depth and quality [29]. Where at least one brackish well exists, water availability was set to 0.004 Mm^3/d.

2.2. Retrofit cost models

Each of the retrofit options carries a very different set of costs. The interest here is to establish a consistent and comparable

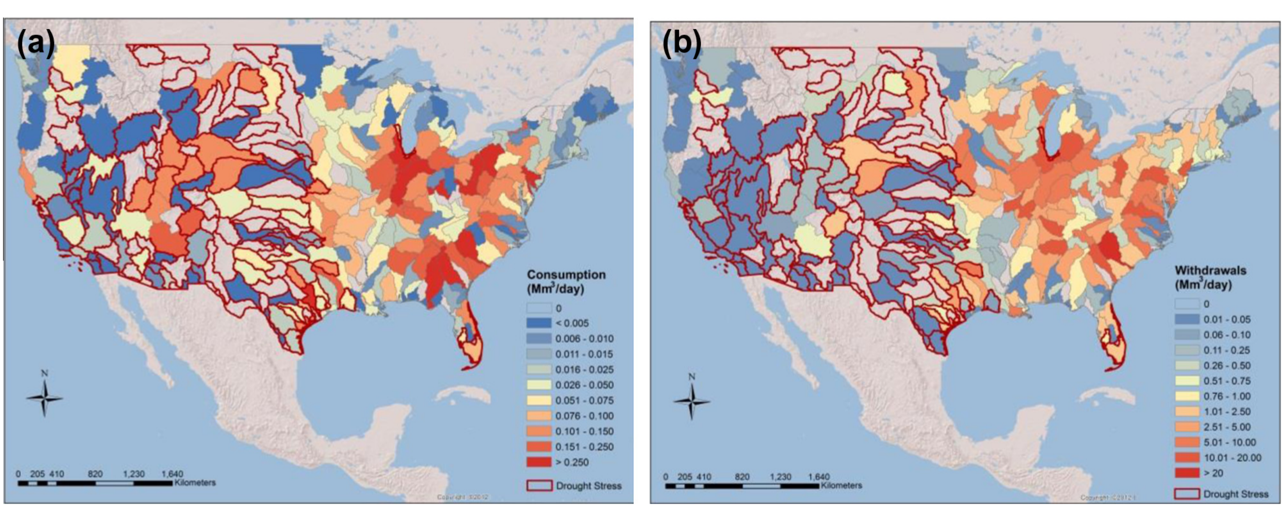

Fig. 1. Consumption (a) and withdrawal (b) of freshwater by thermoelectric power plants mapped at the 6-digit HUC level. Watersheds vulnerable to drought are outlined in red (watersheds mapped in red in Fig. 2) (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.).

measure of cost for power plant retrofit. Costs are calculated for individual power plants and consider both capital as well as operating and maintenance (O&M) costs. All capital costs are amortized over a 30-yr horizon and assume a discount rate of 6%. In this way, total costs are reported in terms of the change in the Levelized Cost of Electricity (ΔLCOE) caused by a retrofit to dry cooling or a non-potable source of water.

2.2.1. Retrofit to recirculating cooling and dry cooling

Capital cost retrofit expenditures and O&M cost increases were assumed to be average difficulty retrofits based on EPA definitions (high difficulty costs were also considered to provide a bounding calculation) [33], and fuel-specific cost rates were applied to plants on a $/kW basis (Table 1). Results can vary greatly depending on the difficulty of retrofits. Retrofit cost factors and performance penalties from a variety of sources were selected to determine fuel-specific values [19,33–40]. Current capital costs and cost components associated with newly constructed facilities were also considered to provide cost estimates consistent with present-day technologies [40,41]. Cost and performance characteristics of different cooling systems, along with retrofit assumptions, are summarized in an NREL technical report [42]. This analysis did not consider the technical feasibility of retrofitting for each individual power plant. In some cases, there may not be sufficient land space or there may be other technical factors that prevent a retrofit from occurring [14]. In addition, retrofit costs and performance penalties may differ greatly from site to site, and retrofit costs at individual facilities may be substantially greater (or less) than average values developed through this coarse national-level analysis [14,43]. Future studies can build off this analysis by utilizing site-specific cost and performance criteria that take into consideration individual power plant and local climate characteristics.

2.2.2. Retrofit to municipal wastewater

Estimated costs consider expenses to lease the wastewater from the municipality, convey the water to the new point of use, and to treat the wastewater (Table 2). Fees charged to lease treated wastewater from the municipality were estimated based on the initial work of Electric Power Research Institute (EPRI) [16]. Values reported in the EPRI report were verified and updated as necessary based on a review of fees published on line. As no geospatial or plant related trends were noted in the pricing an average of the reported fees was adopted for this study, which was calculated at $0.32 per cubic meter.

Conveyance of treated wastewater from the treatment plant to the point of use is a potentially important cost. Considered are both capital construction costs for a pipeline and O&M costs principally related to electricity for pumping. Associated costs calculations are consistent with Watson and others [44]. These costs depend on the distance between the treatment plant and point of use. Here, the straight line distance from the power plant to the nearest wastewater treatment plant with sufficient effluent discharge to meet full cooling requirements was determined—not to exceed 40 km or cross state boundaries.

Degree of wastewater treatment is classified according to three categories, primary, secondary and advanced, listed from least to greatest level of treatment. The degree of treatment currently employed at each wastewater plant is available through the EPA [27,28]. The greater the degree of treatment by the wastewater plant means less additional treatment is required to prepare the water for use by a power plant. It is assumed that all wastewater must be treated to advanced standards before it can be re-used. This conservative assumption was adopted considering both realized improvements in downstream operations (e.g., increased cycles of concentration, reduced scaling, improved feed quality) and the current trend of regulation toward requiring advanced treatment [16]. Plants operating at primary or secondary treatment levels [27,28] are assumed to be upgraded to advanced standards. Capital construction costs are based on the analysis of Woods and others [45], which scale according to treatment plant throughput and original level of treatment. Associated O&M costs consider expenses for electricity, chemicals and labor.

2.2.3. Retrofit to brackish groundwater

Estimated costs consider both capital and O&M costs to capture and treat the brackish groundwater (Table 3). Cost calculations follow basic standards outlined in the Desalting Handbook for Planners [44]. Capital costs include expenses to drill and complete the necessary groundwater wells and construct a treatment plant utilizing reverse osmosis. Number of wells and treatment plant capital costs are based on the treated volume of water. Other key design parameters include the depth of the brackish water and TDS. These data, averaged at the 6-digit HUC level, were estimated from available brackish groundwater well logs [29]. O&M costs capture expenses for labor, electricity, membranes and brine disposal [44].

2.3. Drought vulnerable regions

A simple metric is used to identify regions vulnerable to drought. This measure is similar to that used in the Annual Water Adequacy Analysis conducted as part of the Second National Water Assessment [46]. Drought Vulnerability (*DV*) is represented as the ratio of water demand to water supply within a given watershed:

$$DV = \frac{CU_w + CU_u}{Q + CU_w + CU_u} \tag{1}$$

Table 1
Capital and O&M costs, distinguished by fuel type, to retrofit a power plant from once-through to recirculating cooling, once-through to dry cooling, and recirculating to dry cooling. In the case of capital costs both average and difficult retrofit estimates are given. Data are from Woldeyesus et al. [42].

	Capital cost (once-through to recirculating) ($/kW)	Capital cost (once-through or recirculating to dry) ($/kW)	Capital cost (once-through to recirculating) ($/kW)	Capital cost (once-through or recirculating to dry) ($/kW)	O&M cost (once-through to recirculating) ($/kW/yr.)	O&M cost (once-through to dry) ($/kW/yr.)	O&M cost (recirculating to dry) ($/kW/yr.)
	Average difficulty retrofits		Difficult retrofits		All retrofits		
Coal	90	220	140	330	2	5	3
Natural gas combined cycle	40	170	65	270	2	10	8
Nuclear	90	220	140	330	2	5	3
Biopower/biogas	90	220	140	330	2	5	3
Oil/gas simple cycle	90	220	140	330	2	5	3
Geothermal	N/A	170	N/A	270	N/A	N/A	2
Concentrating Solar power	N/A	170	N/A	270	N/A	N/A	2

Table 2
Capital and O&M costs to retrofit a power plant to use municipal wastewater rather than fresh water. Costs are distinguished by level of difficulty ranging from no need for additional treatment (conveyance system only) to the need for increased treatment (e.g., primary to advanced treatment). Also shown are the median water withdrawal intensities for different types of power plants (all assume recirculating cooling) [26]. Although not shown, capital and O&M costs vary by plant capacity. For illustration and comparison purposes, values given in the table assume a plant capacity of 300 MW and a distance of 10 km between the power plant and wastewater treatment plant.

	Average water intensity (gal/MW h)	Capital cost (conveyance system only) ($)	Capital cost (primary to advanced treatment) ($)	Capital cost (secondary to advanced treatment) ($)	O&M cost (primary to advanced treatment) ($/yr.)	O&M cost (secondary to advanced treatment) ($/yr.)
Coal	587	7.5	40	21	2	1
Natural gas Combined cycle	255	6	27	12	1	0.5
Nuclear	1101	11	53	31	5	3
Biopower/biogas	878	10	48	27	4	2
Oil/gas simple Cycle	1203	11	55	33	6	3
Geothermal	270	6	27	12	1	0.5
Concentrating Solar power	906	9.5	48	27	4	2

Dollars expressed in millions

Table 3
Capital and O&M costs to retrofit a power plant to use brackish groundwater rather than fresh water. O&M costs are distinguished by brackish groundwater concentration. Also shown are the median water withdrawal intensities for different types of power plants (all assume recirculating cooling) [26]. Although not shown, capital and O&M costs vary by plant capacity. For illustration and comparison purposes, values given in the table assume a plant capacity of 300 MW and depth to groundwater of 150 m.

	Average water intensity (gal/MW h)	Capital cost ($)	O&M cost (⩽2500 ppm) ($/yr.)	O&M cost (>2500 ppm) ($/yr.)
Coal	587	26	2	3
Natural gas Combined cycle	255	14	1	1
Nuclear	1101	43	3	5
Biopower/biogas	878	36	2	4
Oil/gas simple cycle	1203	46	3	5
Geothermal	270	14	1	1
Concentrating solar power	906	37	2	4

Dollars expressed in millions

Water demand is measured as the consumptive use of water both within the watershed (CU_w) and that occurring upstream of the basin (CU_u) while water supply (Q) is taken as the gauged streamflow. To reflect drought conditions the measure of physical water supply (Q) used in calculating DV is the 20th percentile flow, or that flow which is exceeded 80% of the time. The effects of drought are most acute when water demand is at a maximum, which generally occurs in late summer. While summer maximum water demand data is not available, a conservative estimate (both CU_w and CU_u) is derived from the annual average demand data [47]. Specifically, annual average thermoelectric water consumption was increased by 12% to reflect higher electricity demands [48] and higher evaporation rates during the summer. Irrigation demands were increased by a factor of 1.5, conservatively assuming uniform irrigation occurs over 8 rather than 12 months out of the year. Municipal consumption was increased by a factor of 1.5 to reflect that most outdoor irrigation is also limited to an 8-month window. Consumption in all other use sectors was maintained at their average levels.

Drought vulnerability for 2009 is mapped at the 6-digit HUC level in Fig. 2. As this ratio approaches 1, the consumptive use of water approaches the physical supply, thus the vulnerability to drought increases. For purposes of this analysis, drought vulnerable watersheds are taken as those with a DV value of 0.7 or higher [46]; that is, those watersheds where the demand accounts for 70% or more of the physical supply.

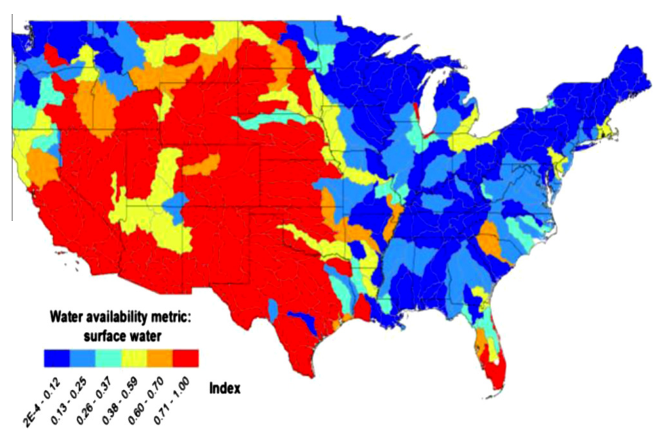

Fig. 2. Drought vulnerability mapped at the 6-digit HUC level, the metric is based on the ratio of water demand to water supply (Eq. (1)). Higher metric values (⩾0.7) indicate regions most vulnerable to drought.

2.4. Retrofit assessment

A simple search and costing algorithm was developed to determine the least cost retrofit alternative for each power plant. This algorithm was implemented using the commercial system dynamics modeling package, Powersim Studio 9 Expert (www.powersim.com). The model sequentially steps through each of the 1178 power plants in the United States that use freshwater in a steam cycle. For each plant it first determines the availability of brackish water and wastewater. For wastewater the 50 closest wastewater treatment plants to the power plant are identified (no further than 40 km away, and located in the same state as the power plant) using Approximate Nearest Neighbor (ANN) software [49]. The cost is then calculated for retrofitting any once-through cooling to recirculating cooling, and then for all power plants to retrofit to dry cooling, and brackish groundwater/wastewater (if a sufficient supply is available). In addition, the amount of electricity required to pump and treat the water (if applicable) is calculated, as is any lost energy production due to reduced efficiencies associated with the change to recirculating and dry cooling. The least cost alternative is then selected and the available water supply reduced to reflect any new use of brackish or wastewater. Finally, results are aggregated at the 6-digit HUC level for display.

3. Results

For purposes of this analysis, every power plant that uses freshwater in generating electric power is assumed to retrofit to dry cooling or a non-potable supply of water, resulting in zero withdrawal of freshwater for thermoelectric cooling. Obviously such changes make little sense for power plants with low vulnerability to drought; likewise, plants that would require prohibitively expensive retrofits are more likely to retire rather than to retrofit. Nevertheless, this analysis provides a scoping level evaluation of the extent to which retrofits to eliminate freshwater use can help reduce vulnerability to drought or improve freshwater availability.

Fig. 3 shows the cumulative frequency plots of the ΔLCOE values for each of the three technology retrofit options calculated for each of the 1178 freshwater thermoelectric power plants in the U.S. Note that 19% of the wastewater retrofits and 59% of the brackish groundwater retrofits have ΔLCOE values equal to $0/MW h. These zero ΔLCOE values simply reflect locations where there is an insufficient supply of wastewater and/or brackish water in the vicinity of the power plant. Specifically, 221 power plants lacked access to wastewater, generally plants with relatively large water requirements (>0.04 Mm^3/d). In terms of brackish groundwater, 696 power plants lacked access to sufficient supply, principally plants located in the Eastern U.S. (Fig. 4). In some cases this deficiency might be reduced by allowing one power plant to access more than one wastewater plant or a brackish groundwater source outside its watershed; however, this would increase costs and logistics.

Another feature evident from comparing the ΔLCOE values across the three retrofit options is the difference in cost. On average, costs tend to be greatest for the dry cooling option. When compared on a plant level basis dry cooling is on average $12.31/MW h more expensive than wastewater and $6.59/MW h more expensive than brackish groundwater. Review of Fig. 3 might lead one to conclude that a brackish groundwater retrofit is the cheapest alternative. However, this is simply an artifact of the limited number of plants for which there is sufficient supply. When considered on a plant level basis brackish groundwater is on average $1.35/MW h more expensive than a wastewater retrofit. In terms of capital costs, the wastewater retrofit is least expensive (average capital costs of $11.9 million), then brackish groundwater (average capital costs of $13.8 million), followed by a retrofit to dry cooling (average capital costs of $114.5 million). However, O&M costs for brackish water treatment are highest among the three options.

Also evident across the three retrofit options is the distinct variation in ΔLCOE among the individual plants. There are many interrelated factors that distinguish the ΔLCOE for different plants and the different retrofit options. For wastewater retrofits a significant factor is whether the power plant requires retrofitting to recirculating cooling, whether additional water treatment is required and the distance between power plant and wastewater plant also plays heavily into the cost. ΔLCOE values for brackish water retrofits are influenced by whether a retrofit to recirculating cooling is required, as well as the TDS and depth of the brackish groundwater. For dry cooling ΔLCOE values are distinguished by fuel type and lost electricity revenue due to reduced production efficiency. Finally, for all three options, smaller plants are most costly to retrofit on a per MW capacity basis (an economy of scale issue). Also, plants with low capacity factors (e.g., peaking plants) have some of the highest ΔLCOE values due to low overall power production.

Also shown in Fig. 3 is the cumulative frequency of ΔLCOE values for the least cost retrofit alterative; that is, the least cost option among wastewater, brackish groundwater, and dry cooling plotted for each of the 1178 freshwater using power plants. The ΔLCOE values range roughly from $0.20 to $20/MW h with a median value of $3.53/MW h. There are 53 power plants with ΔLCOE values above $20/MW h, with a maximum value of $390/MW h. These unusually high values are associated with power plants with low capacity factors (below 5%) which inflate cost on a per MW h basis. In fact, these plants only account for about 3% of total electricity generation.

Based on the least cost alternative of the 1178 power plants, 807 are projected to retrofit to wastewater, 209 to dry cooling and 140 to brackish groundwater. In 180 of the 209 cases where dry cooling was the least cost alternative, dry cooling was the only option available to the plant (wastewater and brackish groundwater supply were insufficient in that location to meet power generation demands). When brackish groundwater was projected as the least cost alternative, it outcompeted wastewater only 50 times. Thus, sufficient availability of wastewater and brackish groundwater was a leading determinant of the least cost option. Fig. 4 shows the locations of individual plants and their projected least cost retrofit option. Evident in this map is that the brackish groundwater retrofits are largely limited to the Southwest, Texas, and Oklahoma. In contrast, wastewater and dry-cooling retrofits are relatively evenly distributed over the entire country. However, a little closer inspection reveals that many of the wastewater retrofits are co-located with metropolitan areas.

The aforementioned costs assume average difficulty in terms of the retrofit from once-through to recirculating cooling or wet to dry cooling. High difficulty retrofits can add 150–270% to the

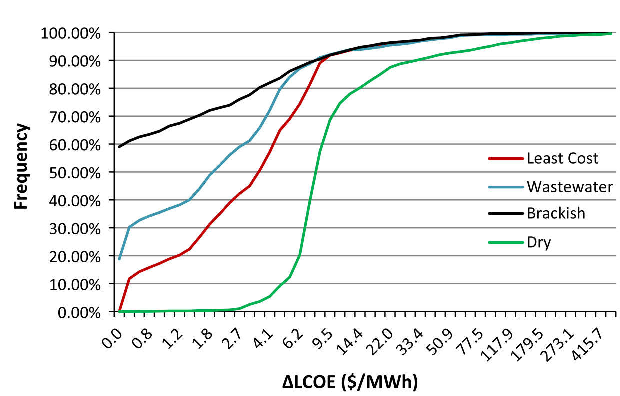

Fig. 3. Cumulative frequency plots of the ΔLCOE values for each of the three technology retrofit options calculated for each of the 1178 freshwater using thermoelectric power plants in the U.S. Also shown is the cumulative frequency of the ΔLCOE for the least cost retrofit alterative at each plant.

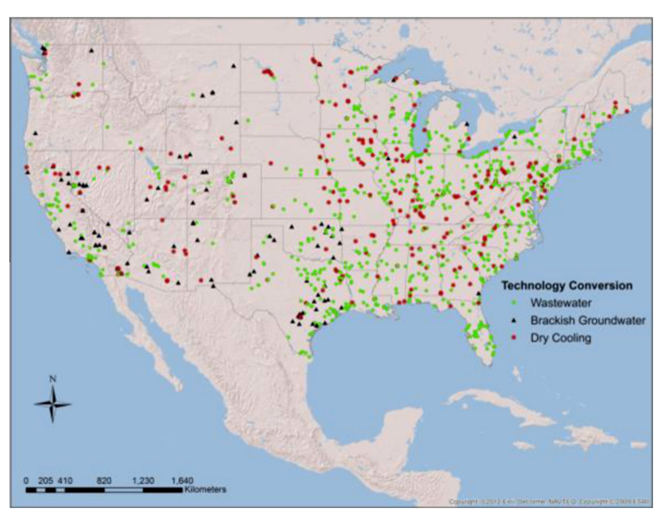

Fig. 4. Least cost retrofit option for each of the 1178 freshwater using thermoelectric power plants in the U.S.

capital expenditures for the retrofit [43]. Median ΔLCOE value for the 1178 power plants under high difficulty retrofit conditions shift from \$3.53 to \$3.85/MW h or a 9% increase. In general, increased costs are only realized by the most expensive retrofits, once-through/recirculation or wet/dry. In total, least cost ΔLCOE values were affected at 557 plants in which the impacts ranged from 3% to 95% of the average difficulty costs. Also noted was that 18 plants that would have retrofitted to dry cooling under average difficulty costs, retrofit to either wastewater (10 plants) or brackish groundwater (8 plants) under high difficulty costs.

If all 1178 power plants are retrofitted, 18.4 Mm^3/d of freshwater consumption would no longer be required for thermoelectric generation and 540 Mm^3/d of thermoelectric water withdrawal would no longer be required. These potential water savings are not uniformly distributed but vary significantly across the U.S. Fig. 1 maps thermoelectric consumption and withdrawal aggregated at the 6-digit HUC level. Water consumption is greatest in the Mid-West, Atlantic Coastal, Texas Coastal, and Mountain West, generally the result of large coal and/or nuclear powered electricity generation. Thermoelectric withdrawals tend to be concentrated largely in the East, corresponding to the extensive use of open-loop cooling systems in these regions. Retrofitting to zero freshwater use would benefit the West through reduced water consumption in basins with limited water availability, freeing up its use for other sector demands or for the environment. Alternatively, reduced freshwater withdrawals would benefit the East through reduced environmental impacts associated with water intake structures (potential new EPA regulation [50]) and reduced vulnerability to drought over thermal discharge limits.

Of particular importance is potential water savings in basins vulnerable to drought. To help visualize where these potential savings occur, drought vulnerable watersheds are outlined in red on the maps of thermoelectric consumption and withdrawal (Fig. 1). There are 123 drought vulnerable watersheds, predominately located in the West and Florida, of which 72 have some form of thermoelectric production located in the basin. A total of 3.2 Mm^3/d of consumption by thermoelectric power generation could be saved, or about 17% of all thermoelectric freshwater consumption if zero freshwater use was achieved. Power plants located in these basins represent some of the highest priority for retrofitting.

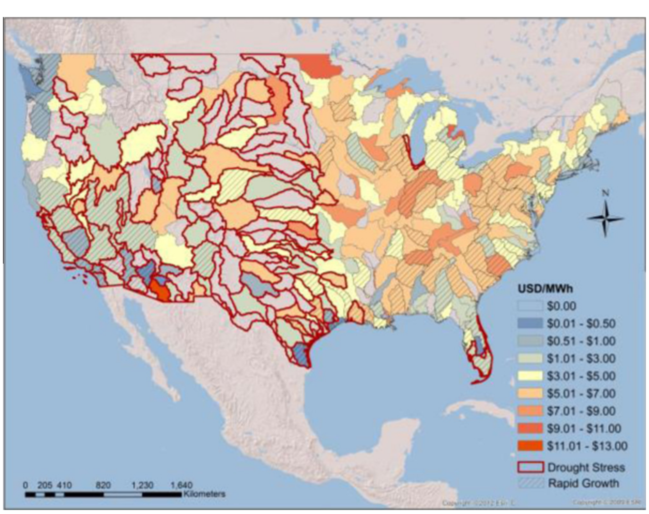

Fig. 5. Least cost alternative ΔLCOE values associated with retrofitting to dry cooling or wet cooling using non-potable water aggregated and mapped at the 6-digit HUC level. Watersheds vulnerable to drought are outlined in red (watersheds mapped in red in Fig. 2) (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.).

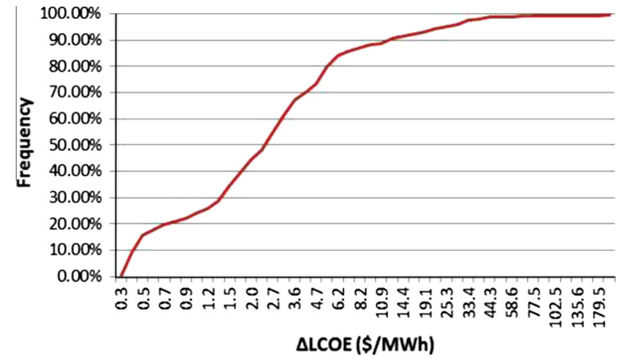

Fig. 6. Cumulative frequency plot of the least cost alternative ΔLCOE values for plants located within drought vulnerable watersheds.

Fig. 5 presents least cost option ΔLCOE values aggregated and mapped at the 6-digit HUC level. The aggregate ΔLCOE for a given HUC was calculated as the production (MW h) weighted average of all plants in the watershed. A positive result is the apparent lower ΔLCOE values in the West and South Florida-areas vulnerable to drought (watersheds outlined in red). To explore this issue in more detail a cumulative frequency plot of the least cost alternative ΔLCOE values for plants located within drought vulnerable watersheds is given in Fig. 6. A total of 327 plants are located in drought vulnerable watersheds. ΔLCOE values range roughly from \$0.3/MW h to \$20/MW h with a median value of \$2.40/MW h. The median value is over a dollar cheaper per MW h than the national average, suggesting good opportunity exists for retrofitting some of the highest priority power plants. A total of 22 power plants have ΔLCOE values above \$20/MW h which produce a little less than 9% of the cumulative power production in drought vulnerable watersheds. The average lower costs are likely the result of several factors, including lower density of power plants in the West and thus less competition for wastewater, fewer plants requiring retrofitting from open-loop cooling to recirculating cooling, and greater availability of brackish groundwater.

Of concern is the potential impact of these retrofits on non-potable water resources and increased demand for electricity. The estimated impact of retrofits on wastewater and brackish groundwater supply is minimal. Aggregate retrofits result in 10.9 Mm^3/d of new wastewater use and 2.4 Mm^3/d of brackish groundwater use. These levels of use represent about 0.7% and 2% of the annual available supply of treated wastewater and brackish water, respectively. Electricity demands are potentially impacted by such factors as the power required to pump and treat water as well as that electricity generation lost due to reduced production efficiencies associated with moving to recirculating or dry cooling. Total parasitic energy requirements are estimated at 140 million MW h, or roughly 4.5% of the total production from the retrofitted plants. Of this parasitic energy loss 118 million MW h are due to efficiency losses with dry cooling retrofits, 12 million MW h are the result of retrofits to recirculating cooling, and 10 million MW h are lost to pumping and treating water. Fig. 4 provides an idea of where parasitic losses will be greatest associated with power plants retrofitted to dry cooling.

4. Conclusions

A scoping level analysis was performed to identify the technical tradeoffs and initial cost estimates for retrofitting existing thermoelectric generation to achieve zero freshwater withdrawal. Considered were plant retrofits to dry cooling or a wet cooling system utilizing municipal wastewater or brackish groundwater. The least cost alternative is determined for each of the 1178 freshwater

using power plants in the United States. Factors considered in the analysis included the local availability of wastewater and brackish groundwater, the need to retrofit to recirculating cooling, capital construction costs (dependent on fuel type, prime mover technology, and cooling type) and O&M costs(e.g., electricity, expendables, labor, disposal). Results indicate numerous affordable opportunities to retrofit, The projected increase in levelized cost of electricity ranged roughly from \$0.20 to \$20/MW h with a median value of \$3.53/MW h. With a wholesale price of electricity running about \$35/MW h, many retrofits could be accomplished at levels that would add less than 10% to current power plant generation expenses. Based on the least cost alternative of the 1178 power plants, 807 are projected to retrofit to wastewater, 209 to dry cooling and 140 to brackish groundwater. This reflects that dry cooling is on average \$12.31/MW h more expensive than wastewater and \$6.59/MW h more expensive than brackish groundwater, while brackish groundwater is on average \$1.35/MW h more expensive than a wastewater retrofit. The choice to retrofit to dry cooling was largely driven by the lack of wastewater and brackish groundwater in the vicinity of the plant.

The estimated impact of retrofits on wastewater and brackish groundwater supplies is minimal requiring about 0.7% and 2% of the annual available supply, respectively. Total parasitic energy requirement are estimated at 140 MMW h or roughly 4.5% of the total production.

Retrofitting to zero freshwater withdrawals could greatly reduce the vulnerability of thermometric power generation to drought. Wastewater and brackish groundwater supplies are largely insulated from the effects of drought. Also, reduced freshwater withdrawal would avoid drought vulnerabilities associated with thermal discharge limits. Additionally, 72 drought vulnerable watersheds (Fig. 5) would realize a decrease in freshwater use and total of 3.2 Mm^3/d of consumption by thermoelectric power generation would be saved. This water would be available for other uses or the environment. Interestingly, the least cost ΔLCOE for these drought vulnerable watersheds is only \$2.40/MW h (median value) which is over a dollar cheaper than the national average.

This analysis did not consider the cost tradeoffs of retrofitting a facility compared with the plant and societal-level costs associated with power plant shut down and curtailment. Nor did this analysis consider the technical feasibility of retrofitting for each individual power plant. In some cases there may not be sufficient land space or there may be other technical factors that prevent a retrofit from occurring. In addition retrofit costs and performance penalties may differ greatly from site to site, and retrofit costs at individual facilities may be substantially greater (or less) than average values developed through this coarse national-level analysis. Future studies can build off this analysis by utilizing site-specific cost and performance criteria that take into consideration power plant and local climate characteristics. These remain areas of future research.

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